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Role of Natural Fractures and Slot Porosity on Tight Gas Sands

Roberto Aguilera, University of Calgary

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Abstract

Naturally fractured tight gas sands have come of age in the United States. They will also come of age in Canada within the next few years and in the rest of the world within the next few decades.

This work discusses the role of natural fractures and slot porosity on tight gas sands as they relate to geoscience, drilling, completion, stimulations, petrophysics, well testing, and reservoir engineering.

It is concluded that natural fractures and/or slot porosity play, and will continue to play, an important role in the successful and economic production of gas from tight sands. Research leading to innovating technologies that presumably will reduce capital and operating costs will play a key role in the development of this resource. Understanding the rocks and the regional variability of fracture distribution and diagenesis is the cornerstone of this research.

Introduction

Tight gas sands are part of what is usually known as unconventional gas which also includes coal bed methane, shale gas and natural gas hydrates. Tight gas sands have been defined in different ways by different organizations but a unique definition has proven elusive.[1] The original definition dates back to the U.S. Gas Policy Act of 1978 that required in-situ gas permeability to be equal to or less than 0.1 md for the reservoir to qualify as a tight gas formation.[2] At present this is probably the most commonly accepted definition. A second U.S. legal definition indicates that in a tight reservoir an average sustained un-stimulated initial gas rate is less than the maximum specified for a given depth class.

However, it is important to understand that, although convenient, not only permeability and/or depth play a role in gas production from tight gas reservoirs. A cursory examination of the pseudo steady state, radial flow equation illustrates that gas rate is a function of many physical factors including pressure, fluid properties, reservoir and surface temperatures, permeability, net pay, drainage and wellbore radius, skin and non-Darcy constant.[3] And this is without adding the effect of natural fractures in the equation. As a result an alternative preliminary definition[1] indicates that tight gas is "contained in low-permeability sandstone and carbonate reservoirs where reservoir stimulation or specialized drilling technology is required to establish economic flow rates and recovery." Another view[3] indicates that "a tight gas reservoir can be deep or shallow, high pressure or low pressure, high temperature or low temperature, blanket or lenticular, homogeneous or naturally fractured, and can contain a single layer or multiple layers. Independent of the definition,[4] "natural fractures are extremely important to unconventional gas reservoirs, and the assessment and characterization of these fractures (and other determinants of permeability) in unconventional plays is a high priority R&D need."

The Bureau of Economic Geology at the University of Texas (Austin) presented an evaluation of Federal, State and private investment in unconventional natural gas research in the US.[5] The study indicates that "the supply curves benefited greatly from natural gas research and the successful application of technology. The tight gas production curve shows a large positive increase in slope in 1985 following $165 million of combined investment in research by the Department of Energy (DOE) and the Gas Research Institute (GRI). Studies were focused on advanced stimulation technology, the greater Green River Basin, and the Piceance Basin." By 1990, 15% of the total U.S. gas production was contributed by unconventional gas. The percentage increased to 40% by 2006, and the DOE estimates that it will increase to 50% by 2025. In Canada, the contribution of unconventional gas to the total was estimated at 25% by 2006, and it is anticipated that it will increase to 40% of the total gas production by 2025.

The Energy Information Administration (EIA) in the 2006 Annual Energy Outlook indicated that unconventional production is the largest source of U.S. gas supply. The EIA also indicates that 9 out the 12 largest natural gas fields in the U.S produce unconventional gas. Commercial production is possible from some tight gas, shales and coal bed methane reservoirs particularly thanks to permeability improvements provided by natural fractures and technological innovations in hydraulic fracturing.

Genesis and Diagenesis of Natural Fractures and Slot Porosity

A fracture is defined as a macroscopic planar discontinuity that results from stresses that exceed the rupture strength of the rock.[6-8] A naturally fractured reservoir contains fractures created by Mother Nature due to stress concentrations or perturbations associated with local deformation. These natural fractures can have a positive or negative effect on fluid flow. In the case of tight gas sands these natural fractures nearly always have a positive effect on fluid flow.

It is not possible to discuss natural fractures without addressing continuously stresses. Paleo-stresses are responsible for the creation on natural fractures found today in tight gas sands. In-situ stresses, i.e., contemporary stresses affect the way in which those natural fractures perform today. Both in-situ stresses and natural fractures (paleo-stresses) affect the results of hydraulic fracturing jobs. The orientations of paleo-stresses and stress magnitudes can change over time and are not necessarily the same as the orientations and magnitudes of contemporary in-situ stresses.

All tight gas sands reservoirs are not created equal. A comparison of tight gas reservoirs in the Western Canadian sedimentary basin and U.S. Rocky Mountain basin is presented in **Table 1**. Because of the differences we have to somehow classify and characterize the reservoirs. This provides an important link between the geoscience and engineering disciplines.

Fracture genesis is associated to paleo-stresses and is attributed to various causes including diastrophism as in the case of folding and faulting, deep erosion of the overburden that permits the upper parts to expand, uplift and fracture through planes of weakness, volume shrinkage as in the case of shales that lose water, cooling of igneous rocks, and desiccation of sedimentary rocks, paleokarstification and solution collapse, fluid pressure release when pore fluid pressure approaches the lithostatic pressure as in the case of geopressured sedimentary strata and meteorite impact that can lead to complex, extensively brecciated systems.[8,9] This fracture genesis allows a generalizaed geologic classification that can be used in the case of tight gas sands. While examining this classification it is important to keep in mind that fractured properties are srongly scale-dependent.

Geologic Classification.- From a geologic point of view underground fractures can be classified as being tectonic (fold and/or fault related), regional, or contractional (diagenetic).[7] Historically most gas production from tight sands has been obtained from tectonic fractures. This is the logic result of companies pursuing the best possible permeability in plays particularly associated with well defined faulting and/or folding. This will continue being an important source for exploration in North America and the world. These fractures can be shear (there is displacement across the fracture face) or extension (there is displacement perpendicular and away from the fracture face) fractures and tend to be pervasive from the large scale to the grain size scale. Thus they tend to be fractal although our current research suggests that they might follow a different distribution. Tectonic fractures are generated by external forces acting upon the rock.

However, there is an important body of tight sands that is mildly deformed and is not necessarily associated with a major tectonic event. Is there any commercial potential in these major sand bodies? Can they have significant and pervasive natural fracturing to nurture the possibilities of commercial production? Enter contractional diagenetic tension or extension fractures. They are probably non-fractal and are created by internal body forces resulting from changes in the surrounding environment. Some of the changes include stresses resulting from thermo-elastic contraction. Enter also slot porosity.

The idea behind contractional fractures and slot porosity in tight gas sands is illustrated with the use of **Figure 1.** Figure 1-a shows a schematic of a rhombohedral packing of spheres that is assumed to represent sand grains. The theoretical porosity in this case is 25.96%. Figure 1-b starts with deposition of the sand and ends at its maximum burial when the vast majority of the porosity has been destroyed, the grains are in pressure solution contact, and the remaining porosity is isolated. Throughout this period, dominated by inelastic processes, the net mean stress increases continuously. Some of the dominant processes include de-watering, porosity and permeability reduction, and hydrocarbon generation and migration.[10]

Figure 1-c starts with onset of uplift and ends with a tight gas reservoir. The figure illustrates a 0.04% decrease in grain radius from cooling during the uplift process. This would be the equivalent of being uplifted from 15,000 to 10,000 ft subsurface. Sediments composed of pure 0.00017 radius quartz grains would generate grain-bounding cracks between 0.2 and 0.4 microns disseminated throughout its matrix.[10] Throughout this period, dominated by elastic processes, the net mean stress decreases continuosly. Some of the dominant processes include formation of faults and fractures in brittle rocks, increases in

permeability, remobilization of first gas and then water and modifications of trapping geometries.[10]
The steps described previously have been used to explain contractional fractures within the domain of tectonic fractures resulting from faulting and folding. However, I hypothesize based on examination of thin sections that the same principle applies away from any major tectonic event in mildly deformed sandstone layers. This topic is currently under investigation by our GFREE research team at the University of Calgary (see section "Future Research" near the end of the paper).

A second way of explaining slot porosity indicates that the majority of pores and pore throats are reduced to narrow slots connecting secondary pores created by grain dissolution.[11] The reduction to slots is the result of primary pores occluded with authigenic cements (quartz or calcite). **Figure 2** presents "photomicrograph and scanning electron microscope images illustrating slot-type pores and pore throats commonly found in low-permeability reservoirs. The slot-type pore network commonly consists of secondary, solution-derived pores that are connected by narrow, sheet-like slots. At overburden stress, these narrow slots compress significantly, reducing permeability. The images shown in the figures are as follows: (A) Frontier Formation, Amoco Shute Creek 1, 10,779.8 ft (3285.6 m), 100, plane polarized light; (B) Williams Fork Formation, MWX 3, 5830 ft (1777 m), 1400; (C) Travis Peak Formation, SFE 2, 8275.3 ft (2522 m), 100, plane polarized light; (D) Travis Peak Formation, SFE 2, 8275.3 ft (2522 m), 100, fluorescent light. Photographs for (B), (C), and (D) are provided (to Shanley et al.[12]) courtesy of D. J. Soeder, U.S. Geological Survey." Another example of slot and fracture porosity displaying a polygonal pattern in the Canadian Triassic is presented in **Figure 3**.

Pore Classification.- Porosity classes are defined first by the geometry of the pores, and second by pore size. [13] Included in the geometry are the following general pore categories: intergranular, intercrystalline, vuggy, and fracture (and/or slot). The combination of any of them can give origin to dual, triple and even multi-porosity and multi-permeability behavior.

The pore size can be recognized from different techniques, including Winland[14] r_{35} and Aguilera[15] r_{p35} pore throat apertures. The two approaches, based on data banks from different formations, provide similar results. Included in the pore throat aperture size are megaports (r_{p35} >10 microns), macroports (r_{p35} between 2 and 10 microns), mesoports (r_{p35} between 0.5 and 2 microns), microports (r_{p35} between 0.2 and 0.5 microns) and nanoports (r_{p35} < 0.2 microns). Experience[16] indicates that in the case of oil megaports are capable of flowing tens of thousands of barrels per day, macroports thousands of barrels per day, mesoports hundreds of barrels of oil per day, and microports tens of barrels per day. Research is under way to try to determine gas production potential from tight sands based on the size of the pore throats.[17]

Figure 4 shows a crossplot of permeability vs. porosity and a preliminary comparison of results from 30,122 siliciclastics reservoirs distributed throughout the world[17] with data from seven U.S. basins where tight gas sands are found.[18] The black thick continuous solid lines represent the upper and lower bounds of porosity and permeability for U.S. basins.[18] The graph shows that microports and nanoports are dominant in tight gas sands. An r_{p35} of 0.5 microns corresponds to a process or delivery speed (k/Ø) of 2.43 md based on the equation[15] shown at the top of **Figure 4.** The figure shows why conventional reservoirs have been developed much faster than tight gas sands.

Storage Classification.- From a storage point of view, fractured reservoirs can be classified[8,19] as being of Type A, B or C. In reservoirs of Type A the bulk of the hydrocarbon storage is in the matrix porosity and a small amount of storage is in the fractures. This is the case of tight gas sands where the fractures provide the necessary permeability that allows fluid flow into the wellbores. In reservoirs of Type B approximately half the hydrocarbon storage is in the matrix and half is in the fractures. The matrix is tight and the fractures are much more permeable than the matrix. In reservoirs of Type C all the hydrocarbon storage is in the fractures with no contribution from the matrix. Thus in this instance the fractures provide both the storage and the necessary permeability required to achieve commercial production.

Influence of Stress Orientation and Anisotropy

Paleo-stresses were responsible for generation of natural fractures and control properties such as strike and dip of fractures. If we assume that the hydrocarbon reservoir is in equilibrium at the moment of discovery, the combination of in-situ stresses and pore pressures affect the architecture of the reservoir from the moment in which the first drop of oil or the first bubble of gas is produced. Natural fractures that are perpendicular to the least principal horizontal stress will tend to remain open as the reservoir is depleted. Natural fractures that are parallel to the least principal stress will tend to close as the reservoir is depleted. The exception is provided by those reservoirs where secondary mineralization plays the role of a natural proppant agent.[20] This proppant agent will help to maintain the natural fractures open as the reservoir is depleted. There are exceptions, however, when the secondary minerals are crushed by in-situ stresses. This situation might create a problem similar to flow of fines.

In the case of tight gas sands the ideal situation is to drill slanted, horizontal, multi-laterals or fish-bone geometry wellbores that go perpendicular to the orientation of the natural fractures. Previous to drilling these wells, however, it is important to perform studies to evaluate wellbore stability.

How to Locate Swarms of Natural fractures

The combination of good geologic understanding, advanced seismic technology, satellite imagery, geomechanical models and innovative thinking can lead to locating subsurface swarms of fractures in tight gas sands. BP[21] has reported on the transfer of offshore wide azimuth seismic technology, used for example to obtain clear images of reservoirs buried beneath salt in the Gulf of Mexico and offshore Angola, to onshore tight gas sands plays with good results. Along the way the approach reduces the operating footprint because the technology involves the use of cable-less seismic receivers which eliminate the need for positioning heavy cables on land.

Seismic velocity reductions can indicate zones of high porosity. Variations in seismic velocity with direction can be related to fractures in the rocks. Wide azimuth seismic acquisition and processing techniques allows detection of natural fractures, which appear as wavy - or sinusoidal - reflectors on the seismic data. The recognition of fractures, slots and the best porosities allows optimum positioning of drilling targets and consequently a reduction in capital and operating costs.

The approach has been used for example for a large scale survey in the Wamsutter gas field in Wyoming, which covers an area of around 4,000 km^2. The reservoir section has a thickness of approximately 600m and is made up of thousands of very thin gas pay zones. It is also being used for evaluation of tight gas sands in the In Amenas and In Salah fields in Algeria and the Khazzan and Makarem gas fields in Oman.

As is usually the case, gas from conventional reservoirs is also present in younger rocks in the above fields, a fact that is of common occurrence in most petroleum provinces around the world. This observation suggests that conventional gas can be used as a proxy for naturally fractured tight gas sands. A variable shape distribution (VSD) model[22] leads to the conclusion that there is a significant potential endowment in tight gas formations that rivals the endowment from conventional gas accumulations (14,200 tcf). Thus, tight gas formations have potential to provide a significant contribution to global energy demand estimated at approximately 722 quads by 2030.[23]

Ant tracking[24] is another approach which offers hope for location of fracture swarms. The technique has been found to be useful for automatic determination of fault surfaces from conditioned fault enhancing attributes. In those instances where the fractures are fault related the method can provide indirect indication of where the fractures are located.

Integrated shear wave splitting, P-wave azimuthal velocity anomalies, cores, image logs, and geomechanical methods[10] have proven also useful for locating natural fractures in three distinct geologic settings and tight gas basins—(1) the Piceance, (2) the Wind River (WRB) and (3) a basin outside the Rockies, the Anadarko. Under favourable conditions it is possible to estimate fracture density and aperture. This technology has been reported to improve significantly the ultimate recoveries in lenticular gas plays of the Rulison field[10] from 0.9 bcf/well in 1956-72 to 2.0 bcf/well more recently. The number of dry holes has dropped from 45% to a low percentage (not reported specifically).

Drilling, Completion and Stimulation

The keys to success in tight gas sands are in my opinion (1) intercepting uncemented gas-bearing fractures, (2) not damaging the fractures, and (3) performing appropriate hydraulic fracturing jobs.

Intercepting the fractures requires knowledge with respect to fracture(s) strike and dip. The accepted concept is that the well must be drilled perpendicular to the fractures. If more than one set of fractures is present, a proper design of the orientation of the slanted or horizontal well can take advantage of the situation.[25]

In conventional drilling the mud weight is chosen to exceed the reservoir pressure so as to avoid potential blowouts. In tight gas sands, however, mud invasion can result in severe formation damage because these formations are highly susceptible to damage. The problem is exacerbated due to the complex geology of tight gas formations, which includes natural fracturing (fluid leak-off), folding and faulting (hard to predict stresses that could make initiation of the fracture difficult or impossible, or fluid loss to the fault which can lead to an early sand-off), channel sands and inter-bedded coals and shales (leak-off into cleats or unexpected fracture propagation paths).

As a result underbalanced drilling appears as a reasonable approach for drilling tight gas reservoirs. In underbalanced drilling, the usual mud is replaced by fluids such as inert gases and foams to make the hydrostatic pressure exerted on the reservoir smaller than the reservoir pressure. This eliminates fluid invasion through fractures and consequently the damage to the tight gas formation. Downhole sensors near the bit gather and send information to the surface. This permits steering the drilling bit through the best portions of the reservoir thus improving the probability of success.[26]

Unfortunately, underbalanced drilling is not a panacea in tight gas sandstones and in fact can induce severe non-anticipated damage. Some of the potential problems include[27] fluid retention, adverse rock-fluid and fluid-fluid interactions, counter-current imbibition effects, glazing and mashing, condensate dropout and entrainment from rich gases, fines mobilization and solids precipitation.

Hydraulic fracturing is necessary in most cases in tight gas formations even when drilling slanted or horizontal wells. However, water retention is a big problem in tight gas sands. As a result many potential solutions have been attempted in the past including pure oil fracs, CO2 energized oil fracs, cross-linked water based fracs, poly-emulsion fracs and water based foam fracs.[27]

More than 1,200 diagnostic fracture injection tests (DFIT) performed in the U.S. Rocky Mountain Area between 1998 and 2001 were evaluated consistently by Craig et al.[28] for estimating permeability, pore pressure and leakoff type. Permeabilities ranged from less than 0.001 to more than 0.1 md. The most common type of leakoff was determined to be the pressure-dependent leakoff, which is indirectly indicative of pervasive natural fracture systems. Warpinski[29] has indicated that fine-mesh sand can help control pressure-dependent leakoff, but scheduling of fine mesh sand is not easy. A key element is to get the fine-mesh sand to the natural fractures as they begin to open. Some success along these lines has been obtained with 100-mesh sand.

For better hydraulic fracturing results in the case of horizontal open boreholes, Hoch et al.[30] suggest two hydraulic fracturing patterns: (1) for wells that are damaged but have natural fractures or high permeability, many small fracturing jobs could be placed in specific locations along the horizontal well to provide the opportunity of breaking vertically through any low permeability barriers and to allow communication with high permeability lenses, and (2) for wells without natural fractures and low permeability, a few large fracturing treatments would provide the opportunity of improved gas productivity through a larger surface area exposed to the formation and consequently larger drainage coverage.

Petrophysics

Dual Porosity Model.- The black squares in **Figure 5** represent core values of Archie's cementation exponent *m* from the tight Postdam formation in Quebec, Canada (Knox equivalent in the U.S) cross-plotted against routine core porosity. All the samples contain fractures. Core permeabilities range between 0.04 and 0.44 md. Lower cementation exponents with decreasing porosity could reflect possible occlusion of the pore system down to a slot pore network. A similar interpretation has been presented for tight gas core samples in the U.S.[18] Evaluation of the core data can be handled with the use of a dual porosity model where the porosity exponent of the fractures (m_f) is ≥ 1.0. The continuous solid line in **Figure 5** matches well the range of the core data and was generated with such dual porosity model (development is presented in **Appendix A**) which is represented by the following equations:

$$\phi^{-m} = \frac{1}{(v\phi)^{m_f} + [1-(v\phi)^{m_f}]/\phi'_b{}^{-m_b}} \qquad \text{…..... (1)}$$

where,

$$\phi'_b = \frac{\phi - \phi_2{}^f}{1-\phi_2{}^f} \qquad \text{……. (2)}$$

and,

$$f = m_f - (m_f - 1)\frac{\ln\phi}{\ln\phi_2} \qquad \text{..….. (3)}$$

Equation (3) is valid for $ø_2 > 0$; *f* has been found to range exponentially between 1.0 at $ø = ø_2$, and m_f at $ø = 1.0$. When fracture porosity is zero, f is equal to 1.0. The value of the porosity exponent *m* can be calculated from:

$$m = \frac{\log\left(\frac{1}{\{(v\phi)^{m_f} + [1-(v\phi)^{m_f}]/\phi'_b{}^{-m_b}\}}\right)}{-\log\phi} \qquad \text{..…… (4)}$$

The partitioning coefficient can be expressed mathematically in different ways:

$$v = \frac{\phi_2}{\phi} = \frac{\phi - \phi_m}{\phi} = \frac{\phi - \phi_b}{\phi(1-\phi_b)} \quad \text{......} (5)$$

Note that the product $v\phi$ in eq.4 is equivalent to fracture porosity ϕ_2 in eq. 5. The relation between ϕ_m and ϕ_b is given by,

$$\phi_m = \phi_b(1 - v\phi) \quad \text{.......} (6)$$

where all symbols are defined in the nomenclature section. **Table 2** shows the calculation of the *m* values used to match the core data (black squares) in **Figure 5**. The results for the model fit the laboratory data reasonably well using $mf = 1.2$, $m_b = 1.77$ and $\phi_2 = 0.0065$. The value of the "slot porosity" (ϕ_2) indicate that gas storage within the slots is very small compared with the storage in the remaining porosity. But the slots provide the permeability that allows the fluids to flow. Their geometry, however, makes them susceptible to partial closure as net stresses increase on the slots. The availability of reasonable values of *m* permits calculation of more realistic water saturations.

Pendular Rings.- The geometric configuration of the slots discussed previously and its relation to the wetting (water) and non-wetting (gas) fluids in a pendular regime of saturation can be approximated by considering a model made out originally of spheres (similar to the geologic configuration shown on **Figure 1-a**), where the porosity decreases significantly as the depth of burial is approached (similar to **Figure 1-b**) and where slots are created due most likely to stresses emanating from thermo-elastic contraction during uplifting of the rocks (similar to **Figure 1-c**).[31]

Well Testing

The biggest problem faced on well testing of tight gas sands is that, because of the extremely low permeabilities associated with these reservoirs, very long times are required to reach the infinite-acting radial flow period. So, it is neither practical nor economic to perform these conventional tests. Because of this, several simplifications are made in order to come out with possible solutions to well testing problems. Probably the biggest simplification is ignoring the presence of natural fractures and slot porosity on well testing effects.[32] Natural fractures, as discussed throughout this paper, are critical for the economic success of these types of reservoirs. If natural fractures are recognized to exist and significant efforts are made to intercept natural fractures with different types of wellbores (vertical, slanted, horizontal, multilaterals, fishbone geometries), why should we ignore those fractures when it comes to well testing?[33] Ignoring their presence might help to explain a significant problem in hydraulic fracturing of tight gas sands where the design half fracture length (x_f) is much larger than the fracture length calculated following the stimulation. As a result, anticipated production increases have not been realized in many cases.[34]

To try to alleviate this problem, Craig et al.[35,36] have developed methods and presented case histories where multiple diagnostic fracture injection tests (DFIT) are used to (1) identify pressure-dependent leakoff resulting from natural fractures opening, (2) identify depleted sand lenses, (3) estimate permeability to gas, and (4) optimize multiple sand completions.

Reservoir Engineering

Estimating gas-in-place and forecasting reservoir performance conveys a certain amount of uncertainty in naturally fractured tight gas sands. Gas-in-place can be calculated volumetrically. On the other hand, material balance calculations have been historically disregarded when dealing with tight gas sands. This is understandable as by the very nature of low permeability reservoirs it takes a very long (sometimes prohibitive) shutin time to reach the infinite-acting radial flow period, from which p* and average pressure can be determined, if the shape of the drainage area is know. Also the shape of the drainage area can be difficult to determine due to the complex nature of tight gas sands, which can include, for example, discontinuity between the sands, faults, natural fractures and inter-bedded coals and shales.

However, there is an alternative material balance that does not require to shut the wells in; the flowing gas material balance.[37] In the conventional material balance for a "volumetric" reservoir a cross-plot of average reservoir pressure over gas deviation factor (p_{avg} / z) vs. cumulative gas production (G_p) leads in some cases to a straight line from which it is possible to calculate OGIP. In the flowing material balance, initial reservoir pressure (p_i) is required for calculating p_i / z_i. For constant flowing pressure (p_{wf}), a cross-plot of flow pressure over gas deviation factor (p_{wf} / z) vs. G_p is parallel to the non-existing straight line that would have resulted from plotting p_{avg} / z. As a result all it takes is shifting the p_{wf} / z vs. G_p straight line without changing the slope until it reaches the control point at p_i / z_i. This procedure requires maintaining the flow rate constant. As this is not always possible, an extension of the method called the dynamic material balance has been developed recently.[38] In the new method the average reservoir pressure is calculated a function of flow pressure, flow rate and a constant.

In some cases, partial fracture closure due to net stress increase on natural fractures[20] can lead to a curvature toward smaller values of gas-in-place in the material balance plot. In other cases the plot can result in a curvature toward larger values of gas-in-place as shown for well 10-33-67-7W6, Falher C formation, Deep Basin, Alberta (**Figure 6**). The interpretation in this case is that the p/z curve depicts a dual transmissivity system. The high transmissivity segment is a sweet spot of conglomerate and/or natural fracturing that provides high gas rates. The sweet spot is encased in a tight sandstone matrix that provides substantial gas storage but low deliverability.[39] For this example the estimated initial gas in place was 10 bcf. Additional gas cumulative and pressure data history indicated a total gas in place of 30 bcf.

In some cases the presence of moveable water can affect the results. These multi-phase flow problems can be handled with a numerical simulator. Given that well spacing is smaller in tight gas reservoirs as compared with conventional reservoirs single well simulators can provide reasonable results in some tight gas sands.

Decline curve analysis using normalized gas rates can provide good results for estimating performance forecast of tight gas sands. If normalization is not possible due to lack of pressure data, hyperbolic declines can be used with, generally, reasonable results.

Future Research

GFREE is a research program in tight gas geoscience and engineering at the University of Calgary.[23] GFREE refers to the integration of geoscience (G), formation evaluation (F), reservoir drilling, completion and stimulation (R), reservoir engineering (RE), and economics and externalities (EE) including environmental and social issues. This acronym highlights our ideas for the mission-oriented research program we are conducting for evaluating the resource base of tight gas in Canada and throughout the world[23] and for finding economic means of extracting as much of this gas as possible.

In our view, the cornerstone of the whole project is the proper geologic (G) understanding of tight gas sands. Understanding the rocks and the regional variability of fracture distribution and diagenesis is fundamental to this research. Fulfilling this step involves working in close cooperation with geoscientists in industry, the University of Calgary, and other Universities and research organizations. This requires, initially, close examination of outcrops. If the quality of the outcrops is good, the next step is conducting 3D studies of selected outcrops. The result will be a virtual 3D view outcrop that can be studied in detail in an immersive visualization room. The validity of the virtual model will be corroborated by drilling, coring and logging very shallow wells in the outcrop. The validated virtual 3D outcrop data (natural fractures, stratigraphy, sand connectivity, and reservoir architecture) will be integrated with subsurface information (cores, cuttings, thin sections…) in an effort to understand the geology of tight gas sands in key areas. The information, combined with in-situ stresses, will prove of paramount importance to engineers trying to unlock gas from tight formations.

The next step deals with formation evaluation (F) by petrophysics and well testing. This segment attempts to develop improved dual and triple-porosity petrophysical methods capable of handling fractures, slots and matrix porosities for differentiating between gas-bearing and water-bearing sands. In addition to evaluating porosity, water saturation, net pay and permeability, these petrophysical models will seek information on pore throat apertures. From these results, we will attempt to generate "rules of thumb" that will provide initial estimates of gas rates from wells drilled in tight gas reservoirs. The goal is very ambitious but in our opinion attainable.

The well testing part of the formation evaluation effort will endeavor to develop better methods for estimating permeability, skin and fracture length, using models that include the known existence of matrix, natural fractures and slot porosities. Although methods for estimating these properties are mature and well established for conventional reservoirs, when it comes to tight gas sands, the methodology is not well developed due to the very low permeability of these types of formations.

The next segment of our research is associated with the reservoir (R); how to access it, how to complete wells in it and how to stimulate the wells. The key ideas are intercepting natural fractures, not damaging the fractures and developing the correct hydraulic fracturing procedure. This will require a comparison of vertical vs. slanted vs. horizontal vs. multilateral vs. fish-geometry wells.

The reservoir engineering (RE) segment includes an estimation of the resource base in naturally fractured tight gas sands. Volumetric and material balance evaluations; and how to determine the optimum well spacing will be conducted in this part of the project. This will be supplemented by production decline analysis. Results of our research will have to be corroborated with pilot wells.

Finally, the proposed research will keep an eye on the triple bottom line. Our idea is that we will research those items that present good probabilities of being economic (the first E in the acronym). The technological innovations discussed in previous paragraphs presumably will lead to reductions in capital and operating costs. These innovations have to be supplemented by environmental and social issues, i.e., sound externalities (the last E in the acronym). Production decline rates must lead to positive cash flows and rates of return that are attractive to companies operating in Canada and elsewhere. In the long run, we will attempt to develop methods for estimating volumes of undiscovered resources with the goal of generating cumulative long run availability curves for Canada and the rest of the world.

We anticipate that the research program will result in the delivery of highly qualified professionals, with significant knowledge of tight gas formations, needed by industry and research organizations. Evaluating the current status of geologic models, reservoir characterization, recovery and production technologies currently available for these types of formations is the first step in the effort to reach the final goal: finding economic means of producing as much of this gas as possible.

Conclusion

Natural fractures and/or slot porosity play and will continue to play an important role in the successful and economic production of gas from tight sands. Research leading to innovating technologies that presumably will reduce production costs will play a key role in the economic development of this resource. Understanding the rocks and the regional variability of fracture distribution and diagenesis is the cornerstone of this research.

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Nomenclature

F - Formation Factor
F_t - Formation Factor of the Composite System
m - Dual Porosity Porosity Exponent (Cementation Factor)
m_b - Porosity Exponent (Cementation Factor) of the Matrix Block
m_f - Porosity Exponent (Cementation Factor) of the Fracture System
R_{fo} - Resistivity of the Composite System (Matrix plus Fractures) When it is 100% Saturated with Water (ohm-m)
R_w - Water Resistivity at Formation Temperature (ohm-m)
v - Partitioning Coefficient
$ø$ - Total Porosity
$ø_b$ - Matrix Block Porosity Attached to the Bulk Volume of the Matrix System
$ø'_b$ - Matrix Block Porosity Affected by m_f
$ø_m$ - Matrix Block Porosity Attached to the Bulk Volume of the Composite System
$ø_2$ - Porosity of Natural Fractures

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APPENDIX A

Development of Dual-Porosity Model for Reservoirs made up of matrix Porosity and Natural Fractures when the Porosity Exponent of the Fractures (m_f) is Greater than 1.0

This type of reservoir can be modeled with a parallel resistance network. The resistivity of the composite system when it is 100% saturated with water is equal to R_{fo} and can be defined as follows when $m_f = 1.0$:

$$\frac{1}{R_{fo}} = \frac{v\phi}{R_w} + \frac{(1 - v\phi)}{R_o} \quad \text{…..… (A.1)}$$

When $m_f > 1.0$, the equation is written as:

$$\frac{1}{R_{fo}} = \frac{(v\phi)^{m_f}}{R_w} + \frac{[1 - (v\phi)^{m_f}]}{R_o} \quad \text{……… (A.2)}$$

The equation can be re-written as follows:

$$R_{fo} = \frac{R_w R_o}{(v\phi)^{m_f} R_o + [1 - (v\phi)^{m_f}] R_w} \quad \text{……… (A.3)}$$

Taking R_o as a common factor in the denominator leads to:

$$R_{fo} = \frac{R_w R_o}{R_o \{(v\phi)^{m_f} + [1 - (v\phi)^{m_f}] R_w / R_o\}} \quad \text{……… (A.4)}$$

The basic formation evaluation equations for only the matrix are:[40]

$$R_o = F R_w \quad \text{……… (A-5)}$$

and,

$$F = \phi_b^{-m_b} \quad \text{……… (A.6)}$$

The basic formation evaluation equations for the composite system of matrix and natural fractures are:

$$R_{fo} = F_t R_w \quad \text{……… (A.7)}$$

and,

$$F_t = \phi^{-m} \quad \text{……… (A.8)}$$

Inserting equations (A.5) and (A.7) into eq. (A.4) leads to:

$$F_t R_w = \frac{R_w R_o}{R_o \{(v\phi)^{m_f} + [1-(v\phi)^{m_f}]/F\}} \quad \text{……… (A.9)}$$

Canceling terms and inserting eqs. (A.6) and (A.8) into eq. (A.9) leads to:

$$\phi^{-m} = \frac{1}{(v\phi)^{m_f} + [1-(v\phi)^{m_f}]/\phi'_b{}^{-m_b}} \quad \text{…..... (A.10)}$$

Where a modification is entered from ϕ_b to ϕ'_b for taking into account the possibility of an $m_f > 1.0$.

$$\phi'_b = \frac{\phi - \phi_2{}^f}{1-\phi_2{}^f} \quad \text{……. (A.11)}$$

and,

$$f = m_f - (m_f - 1)\frac{\ln\phi}{\ln\phi_2} \quad \text{..…... (A.12)}$$

The equation is valid for $\phi_2 > 0$; f has been found to range exponentially between 1.0 at $\phi = \phi_2$, and m_f at $\phi = 1.0$, using numerical experimentation. The value of the porosity exponent m can be calculated from:

$$m = \frac{\log\left(\dfrac{1}{\{(v\phi)^{m_f} + [1-(v\phi)^{m_f}]/\phi'_b{}^{-m_b}\}}\right)}{-\log\phi} \quad \text{..….. (A.13)}$$

The partitioning coefficient can be expressed mathematically in different ways:

$$v = \frac{\phi_2}{\phi} = \frac{\phi-\phi_m}{\phi} = \frac{\phi-\phi_b}{\phi(1-\phi_b)} \quad \text{...... (A.14)}$$

The relation between ϕ_m and ϕ_b is given by:

$$\phi_m = \phi_b(1 - v\phi) \quad \text{…….. (A.15)}$$

Where all symbols are defined in the nomenclature section**.**

Table 1 – Comparison of Western Canadian Sedimentary Basin and U.S. Rocky Mountain Basin Centered Gas Basin (Source: Zaitlin and Moslow[39]).

Western Canadian Sedimentary Basin (WCSB)	**U.S. Rocky Mountain Basin Centered Gas (BCG) Basins**
Regionally pervasive (?) gas saturation – Gas charged	Regionally pervasive (?) gas saturation
Abnormally (over or under) pressured	Abnormally (over or under) pressured
“Continuous” Foredeep	“Segmented” Basins
Thick succession with isolated thin low net/gross reservoirs	Thick succession with stacked high net/gross reservoirs
Relatively deep (3000 – 4000+ m)	Spectrum of depths (300 – 4000+ m)
Compressional tectonics with isolated-spaced zones of wrenching	Wrench / extensional tectonics dominate
Unconventional reservoir quality with sweet spots of conglomeratic and/or natural fracturing	Tight reservoir quality with fractured sweep spots
Chert to sublithic arenites	Quartz arenites
Non-marine to shallow marine deposits (deep water)	Non-marine to deep water deposits
Single or dual zone completion progressing to multi-zone completions	Commingling of production from multiple reservoirs common

Table 2 – Calculation of dual porosity exponent (m) when the porosity exponent of only the fractures (m_f) is bigger than 1.0

m_b =	1.77
m_f =	1.20
$Ø_2$ =	0.0065

Total Porosity, Ø	**Exponent m_f '**	**Matrix Porosity, $Ø_b$**	**Matrix Porosity, $Ø_m$**	**Dual porosity exponent, m**
0.0066	1.0006	0.0001	0.0001	1.2036
0.0070	1.0029	0.0006	0.0005	1.2178
0.0080	1.0082	0.0018	0.0015	1.2504
0.0090	1.0129	0.0029	0.0025	1.2800
0.0100	1.0171	0.0041	0.0035	1.3070
0.0200	1.0446	0.0149	0.0135	1.4887
0.0300	1.0607	0.0253	0.0235	1.5844
0.0400	1.0722	0.0356	0.0335	1.6397
0.0500	1.0810	0.0459	0.0435	1.6739
0.0600	1.0883	0.0561	0.0535	1.6964
0.0700	1.0944	0.0662	0.0635	1.7118
0.0800	1.0997	0.0764	0.0735	1.7229
0.0900	1.1044	0.0865	0.0835	1.7311
0.1000	1.1086	0.0966	0.0935	1.7373

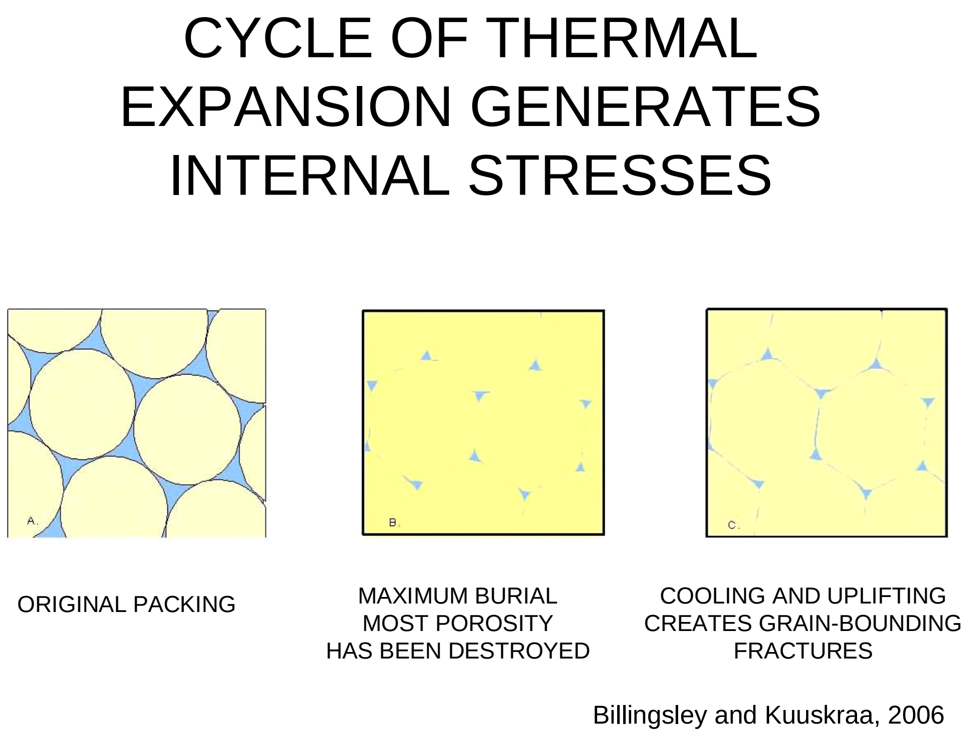

Figure 1 – Cycle of thermal expansion generates internal stresses that can lead to contractional fractures in tight gas sands (Source: Billingsley and Kuuskraa[10]).

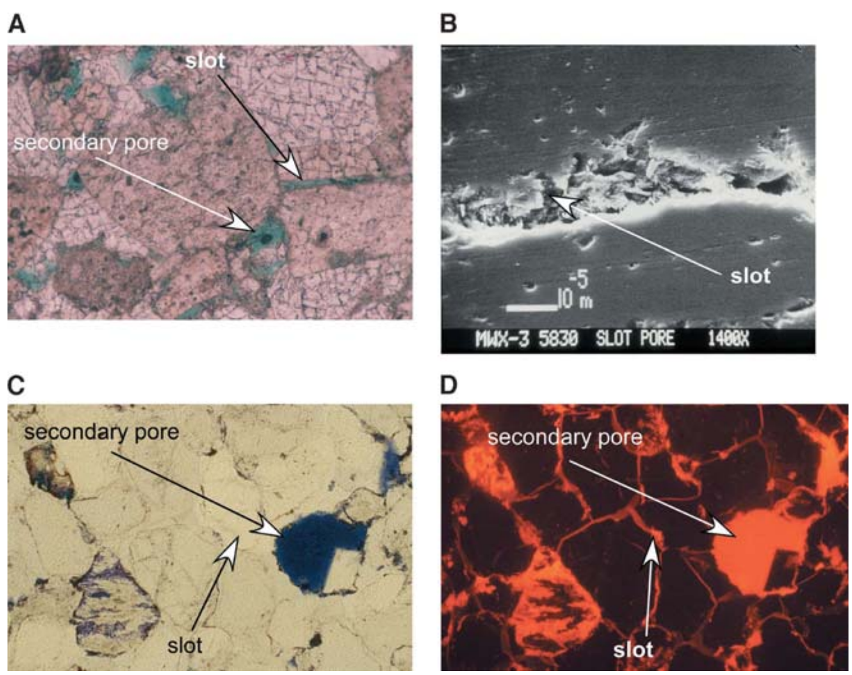

Figure 2 - Photomicrograph and scanning electron microscope images illustrating slot-type pores and pore throats commonly found in low-permeability reservoirs in the U.S. (Source: Shanley et al.[12]).

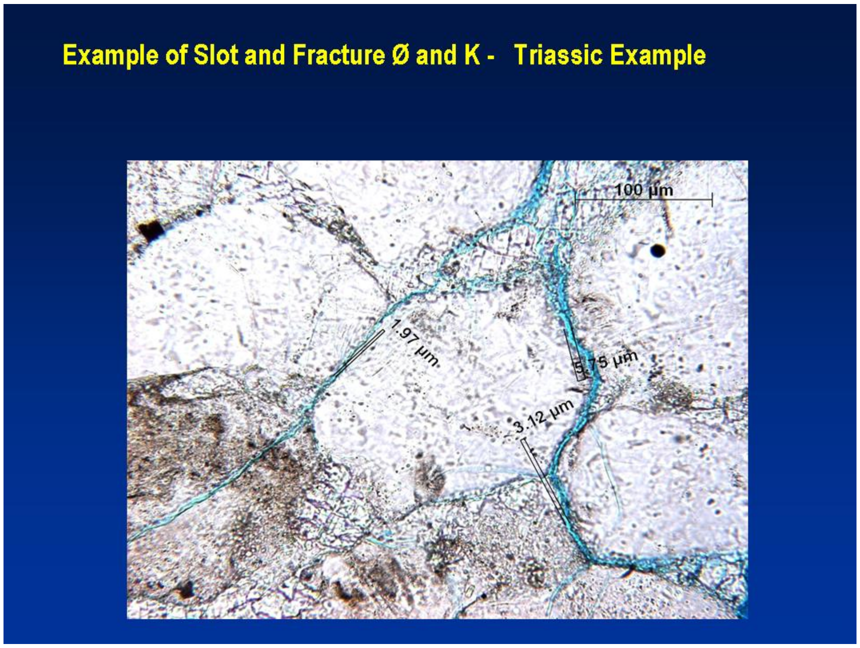

Figure 3 – Thin section of slot and fracture porosity in the Deep Basin of Canada (Source: Zaitlin and Moslow[39]).

GLOBAL PETROLEUM RESERVOIRS: 30,122 SILICICLASTICS RESERVOIRS. Black thick lines represent the bounds of the Byrnes et al. data (Kansas Geological Survey, 2006)

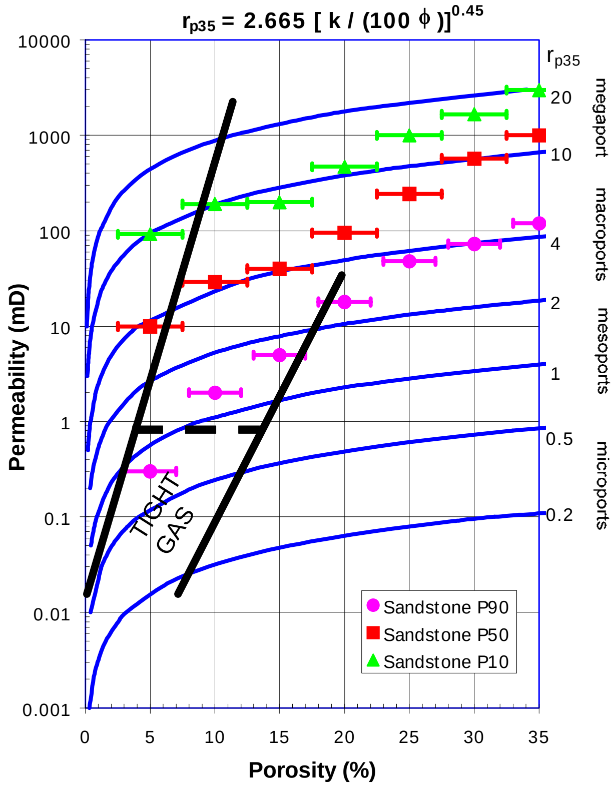

Figure 4 – Tight gas and siliciclastic global petroleum reservoirs (Source: Aguilera and Harding[23]).

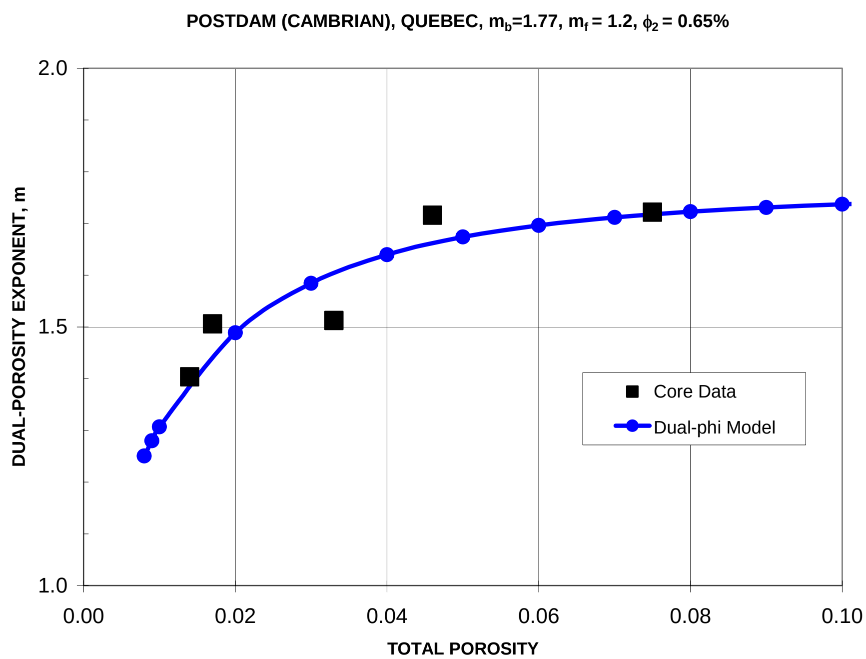

Figure 5 – Values of m decrease in the presence of natural fractures and slot porosity in tight formations. Core permeabilities in this case range between 0.014 and 0.46 md.

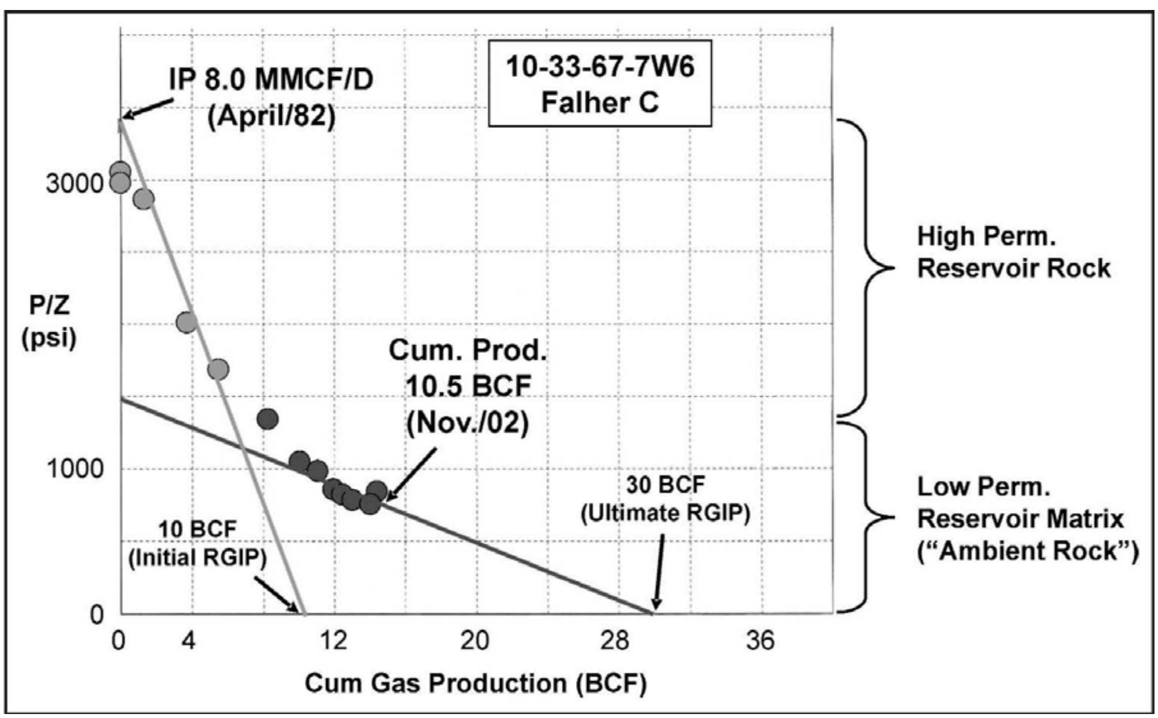

Figure 6 - Characteristic P/Z curve depicting the dual transmissivity nature of a Deep Basin reservoir as observed in the 10-33-67-7W6 well (Source: Zaitlin and Moslow[39]).